May 20, 2008

Jeff Pitzer
Business Unit leader
BP Cherry Point Refinery
4519 Grandview Road
Blaine, Washington 98230

RE: Cherry Point BART Technical Analysis Report

Dear, Mr. Pitzer

We have reviewed the Best Available Control Technology (BART) report submitted by Geomatrix on behalf of your company.

We have a number of questions and issues about the analysis. They are listed in the attachment to this letter.

Please respond to these comments by June 25, 2008.

If you have any questions about our comments, please contact myself at 360-407-6810, (anew461@ecy.wa.gov) or Bob Burmark at 360-407-6812 (rbur461@ecy.wa.gov).

Sincerely;

Alan R. Newman, PE
Senior Air Quality Engineer

Cc: Lynn Billington, NWCAA
Valerie Lagen, BP Cherry Point
Elizabeth Daly, BP Cherry Point
Maureen O'Brien, BP Cherry Point
Eric Hansen, Geomatrix
Bob Burmark, Ecology

Attachment

Attachment 1: BP Cherry Point Refinery BART Analysis Questions

Question 1: BP has stated that the representative average /nominal heat content of the refinery gas used at the plant was 1,352 BTU/ft^3 (2003-2005 data), with an SO_2 emission factor of 0.0364 lb/MMBtu. Swings in refinery gas specific gravity (and heat content) are cited as affecting the viability of several BART options. We know that sulfur content can also vary. What is the range of refinery gas heat and sulfur contents, and how might the heat and sulfur content changes be described statistically over a day, week, or year? What operations and refinery gas component variables drive these changes?

Question 2: In multiple locations there is a discussion on the BART eligible Boilers 1 and 3 that discounts the need for reviewing controls for them. These discussions defer any need to analyze BART controls due to their future decommissioning and removal and replacement by new boilers. What is the project status of the replacement boiler project? Will the boilers be replaced by the end of 2010 as discussed in the report?

Question 3: Section 2.2 (page 6) Please provide additional discussion on your position that an add-on emission control device must meet the same time between maintenance shut-downs as the process heater it would control. The simple statement that a control (such as a dry scrubber for SO_2 control) does not exhibit this capability is not sufficient to classify the control as technically infeasible. For instance, use of a bypass stack might allow a heater to operate uncontrolled for the short time needed for control system maintenance. This would provide flue gas treatment for most of the year. During maintenance, emissions would be like they are now.

Question 4: Section 3 General. The opening paragraph of Section 3.0 (page 13) says that all process heaters and boilers are permitted to use a combination of natural gas and refinery gas. The sulfur emissions factors (Table A-1 SO_2) for some heaters differ from others as a result of source testing of the different units. Why are the SO_2 emission factors for the source tested units higher than the emission factors based on refinery gas sulfur content monitoring? We note that the average of the three different source test emission factors (0.0432 lb/MMBtu) is about 18% higher than the mass balance factor of 0.0364.

Question 5: Section 3.1.1, Page 14. Please translate "burner's performance with fuel gas gravity swings for units with high turndown". Please confirm that 'fuel gas gravity swings' is jargon for changes in the specific gravity of the refinery gas and that the specific gravity of the refinery fuel gas related to the heat content of the gas? How does "high turndown" capability burner design affect performance and emissions?

Question 6: Please direct me to a reference or article discussing the importance of H_2 in the refinery gas on the effectiveness of SNCR.

Question 7: Page 15 and 17. Ecology appreciates that BP has proposed installation of a ULNB on the 1st Stage HC Fractionator Reboiler. For completeness of the analysis and to support our ultimate BART determination, please explain what characteristics of this heater make it conducive to the steam injection and burner modifications that don't exist in other units (those

without LNB or ULNB already installed) where steam injection, burner modifications are rejected as technically infeasible.

Question 8: Section 3.1.3, Page 18. Please support the 5 ppm control effectiveness statement for SCR. Our experience with SCR and the literature on other industries use of SCR does not support the statement that SCR cannot reduce NO_X below 5ppm. Current generation large combined cycle combustion turbine facilities are routinely permitted with NOx limits of 2 ppm with a 9 ppm uncontrolled emission rate. The 5ppm SCR control effectiveness is used several places, including the Diesel HDS Charger Heater & Diesel HDS Stabilizer Reboiler on Page 28, and the Steam Reforming Furnaces #1 and #2 on page 29.

Question 9: Section 3.1.4.1, Page 25. Please provide more detail on why LNB doesn't work on this unit beyond "high heat density". What concept is 'high heat density' supposed to convey? This is only important due to your citing it as a reason why LNB is not feasible or BART.

Question 10: Section 3.1.4.5, Page 27. What is the alternate fuel source which "limits the effectiveness of NOx control technologies?" Earlier in this report you imply that all burners are fueled with natural gas or refinery gas (and maybe both). No alternative fuel usage is noted elsewhere in the report.

Question 11: Section 3.2.4, page 35. Statement that fuel gas conditioning to reduce sulfur will add 1 ton/day to the existing SRU loading. What change in concentration of sulfur compounds in the fuel gas does this 1 ton/day represent? If 50 ppmv (the gas compound is not clear, total S? H2S? COS?) represents 89% reduction, this implies the original fuel gas had 454 ppmv of total sulfur compounds.

Can fuel gas containing 50 ppm total sulfur be attained today without additional expense on new equipment? What changes would be needed to assure a 50 ppm refinery gas sulfur limit can be achieved.

Question 12: Section 3.2.4.1, page 36. Please explain how the cost per ton of fuel gas conditioning was obtained. What new equipment, chemical costs, energy costs are required for fuel gas conditioning? Is cost of fuel gas conditioning ($22,282/ton SO_2) split by SO_2 reduction the same as a split based on fuel consumption? It is intuitive that total project cost divided by the total tons of sulfur compound reduced is the most logical measure. It is not clear if all of the project cost was assigned to the BART units, or if costs were distributed over all refinery gas using heaters and boilers at the plant.

Question 13: Section 3.3.2, Page 39. You discount the use of a baghouse for increased particulate control. One reason is the length of time necessary to coat the bags with a thick enough dust covering to be effective. Is it possible, and what would the additional cost be to include precoating the bags with a chemical dust like sodium bicarbonate or calcium oxide?

It is assumed that particles from gas consumption are all less than PM 2.5, and most are less than PM1.0. Can a bag filter trap these sizes without a large pressure drop across the specially coated or designed bag?

Question 14: Section 4.0, page 46. For our support document we will need some additional detail on the flare operation. Is the flare used only in emergencies, or are some gases from normal operations flared also? What happens to the coker blowdown gas if the equipment involved with collecting the coker blowdown becomes inoperable? Are they directed back to the flare? Has coker blowdown gas had to be directed to the flare due to a failure of the coker blowdown gas collection system?

Question 15: Section 5.1.2, page 50 What is importance of the burner being a "side entering" burner rather than some other orientation? Is this simply a statement that the burner is on the long side of the firebox firing across the width of the firebox rather than the long direction?

Question 16: Concerning Appendix A, Baseline Emissions
Question 16.1: Similarly to Question #4, what is the refinery gas total sulfur content (ppm of sulfur in the refinery gas) used for the baseline emissions, and how does that sulfur content compare to natural gas? Is this refinery fuel gas sulfur content measured before or after blending with natural gas? Is there any blending with natural gas? If the measurement is after mixing of refinery fuel gas and natural gases, what is the annual split between refinery fuel gas and natural gas use?

Question 16.2: Do any units burn fuels other than natural gas or refinery gas?

Question 16.3: Which BART units (if any) burn gas streams that contain nitrogen compounds like ammonia or amine?

Question 17: In Table A-1, please provide additional information on why some units have different SO_2 emission factors. i.e. why some units have an emission factor based on a mass balance from the refinery gas total sulfur content and some have higher emission factors based on source tests.

Question 18: Why are the source test based emission factors higher than the mass balance factor?